TECHNICAL REVIEW DOCUMENT
for
RENEWAL of OPERATING PERMIT 95OPLR073

Colorado State University
Larimer County
Source ID 0690011

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September and October 2003
Revised December 12, 2003, April 6 and June 4, 2004

I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed operating permit proposed for this site. The original Operating Permit was issued October 1, 1998. The expiration date for the permit was October 1, 2003. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal operating permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted September 10, 2002, comments on the draft permit and technical review document submitted on April 5, 2004, additional information submitted on June 1 and August 18, 2004, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This source is a major university classified under Standard Industrial Classification (SIC) 8221. As a university, many varied activities take place on several campuses. However, only the heating plant (SIC 4961) on the main campus and incinerator units at the Center for Disease Control (CDC) and Animal Disease Laboratory (ADL), best classified under SIC 8071, warrant permitting. Colorado State University (CSU) has three campuses and a research park in the city of Fort Collins, Larimer County, Colorado. The heating plant is on the main campus off of Mason Street behind the Gibbons Building. The CDC and ADL are located at the Foothills Campus just off of Rampart Road.

During the pre-public comment review of the draft renewal permit, CSU indicated that they wanted to install a steam turbine (approximately 500 – 1,000 kw) downstream of the three steam generating boilers at the main campus heating plant. The purpose of the turbine is to lower the steam pressure, as generated by the boilers (120 - 160 psig), to the system distribution pressure (40 - 60 psig). In addition, the steam turbine will utilize the steam from the heating plant boilers to generate electricity for use on campus. The addition of the steam turbine is considered a modification (i.e. a physical change or change in the method of operation) of the heating plant boilers. A detailed discussion of this modification is in Section III of this document under “source requested changes”.

In addition, the source did not identify any changes to the insignificant activity list.

Note that none of the boilers or incinerators are equipped with control devices and therefore the Compliance Assurance Monitoring (CAM) requirements to not apply to these units.

The facility is located in Ft. Collins, in Larimer county. The area in which the facility is located is classified as attainment/maintenance for carbon monoxide and attainment for all other criteria pollutants. Under that classification, all SIP-approved requirements for CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to update actual emissions and to revise the potential to emit (PTE) based on the limitations taken on the boilers with the addition of the steam turbine:

Pollutant	Potential to Emit[1]	Actual Emissions – Combination
PM	19.1	2.2
PM_{10}	13.3	1.9
SO_2	42.8	2.8
NO_X	127.7	107.2

Pollutant	Potential to Emit[1]	Actual Emissions – Combination
CO	65.8	35.1
VOC	4.3	2.3
HAPS	7.8	< de minimis

[1]PTE shown in the table is based on emissions from boilers #1, #2 and #3 only, since permitted emissions from the incinerators are less than APEN de minimis levels.

Potential to emit for the boilers is based on permitted emission limits. Potential to emit for HAPs for boilers 1 – 3, is based on AP-42 emission factors and the permitted fuel consumption limit. Potential HAP emissions from boilers 1 – 3 alone, are approximately 1.7 tons/yr. The HAP estimate in the above table also includes hexane emissions from the boilers included in the insignificant activity list, since the AP-42 emission factor for hexane is very conservative. The heat input rate from each of the 79 boilers was assumed to be 10 mmBtu/hr, which is conservative since many are less than 5 mmBtu/hr. Actual emissions are based on APENS submitted on September 10, 2002 with the renewal application.

III. Discussion of Modifications Made

Source Requested Modifications

The source's requested modifications identified in the renewal application were addressed as follows:

The source did not request any specific changes although they indicated that the Responsible Official had changed. Therefore, the Division revised the permit to indicate the new Responsible Official.

In addition, the source indicated, that they may operate one or more non-road engines at the facility, which may be subject to certain "state-only" requirements adopted by the Colorado Air Quality Control Commission in their July 2002 meeting. During the pre-public comment review period, the source indicated that none of their non-road engines were greater than 1,200 hp and therefore, the "state-only" permitting requirements do not apply.

Addition of Steam Turbine

During the pre-public comment review period, CSU indicated that they were planning on installing a steam turbine downstream of the three heating plant boilers. The primary purpose of the steam turbine is to lower the steam pressure, as generated by the boilers, to the appropriate system distribution pressure. As an added advantage, the steam turbine will utilize the steam to generate electricity for use on campus. The addition of the steam turbine is considered a modification (i.e. a physical change and a change in the method of operation) of the heating plant boilers. Since the facility is considered a major stationary source, the net emission increase from this modification must remain below the PSD significance levels or PSD review will be required. The source elected to take emission limits on boilers 2 and 3 in order to keep the emission increase below significance level and avoid PSD review requirements. The source submitted the modification application on June 1, 2004

CSU submitted actual fuel consumption from the 3 boilers for the periods May 2003 – April 2004 and May 2002 – April 2003. Since the boilers are capable of burning either natural gas or No. 2 fuel oil, actual emissions are based on the worst case fuel, in accordance with EPA Guidance Document PSD/98. Note that in their submittal, CSU adjusted upward the actual fuel consumption data since the number of heating degree days (HDD) for the actual emission period was less than the five-year average HDD. While the Division would allow CSU to use a more representative year on which to base actual emissions, we do not consider adjusting the actual fuel use data to make the data more representative to be appropriate. Therefore, the Division's analysis is not based on the HDD adjustment made by CSU. The actual emissions, with subsequent allowable emissions are as follows:

	May 03 – April 04[1]				May 02 – April 03[1]			
Pollutant	Fuel (mmBtu/yr)	Blr 1 and 2 Actual (tons/yr)	Blr 3 Actual (tons/yr)	Total Actual (tons/yr)	Fuel (mmBtu/yr)	B.r 1 and 2 Actual (tons/yr)	Blr 3 Actual (tons/yr)	Total Actual (tons/yr)
PM	Total = 713,069 Boiler 3 = 165,432	6.54	1.98	8.52	Total = 706,028 Boiler 3 = 103,080	7.21	1.23	8.44
PM_{10}		4.56	1.38	5.94		5.02	0.86	5.88
SO_2		14.67	4.31	18.98		16.16	2.69	18.85
NO_X		75.17	11.98	87.15		82.76	7.47	90.23
CO		22.55	6.81	29.36		24.83	4.24	29.07
VOC		1.48	0.45	1.93		1.63	0.28	1.91

[1]Actual emissions are based on "worst case" fuel. For PM, PM_{10} and SO_2 worst case is #2 fuel oil. For NO_X, VOC and CO worst case fuel is natural gas, except for boiler 3, then worst case for NO_X is #2 fuel oil.

The allowable emissions were determined based on adding the PSD significance level minus 1 ton/yr to the average actual emissions. Allowable emissions were determined as follows:

Pollutant	03-04 Actual Emissions (tons/yr)	02-03 Actual Emissions (tons/yr)	Average Actual Emissions (tons/yr)	Allowable Emissions (tons/yr)
PM	8.52	8.44	8.48	32.48
PM_{10}	5.94	5.88	5.91	19.91
SO_2	18.98	18.85	18.92	57.92
NO_X	87.15	90.23	88.69	127.69
CO	29.36	29.07	29.22	128.22
VOC	1.93	1.91	1.92	40.92

CSU had requested flexibility with emissions from the boilers and requested that the fuel oil limit for boiler 1 be removed and that a "bubbled" NO_X and SO_2 emission limit for all three boilers be applied. It is the Division's policy to include a fuel consumption limit, however, to provide flexibility we will include a fuel consumption limit for all boilers combined. In addition, the fuel consumption limit will be in units of lbs/mmBtu and will not limit natural gas and No. 2 fuel oil individually. NO_X emissions appear to be the limiting pollutant, therefore the fuel consumption limit will be based on the allowable NO_X limits. In order to provide the source with the highest fuel consumption limit, the Division reviewed three scenarios: only boiler 1 and/or 2 operating on natural gas, boiler 3 at 8760 hrs/yr and boilers 1and/or 2 for the remainder, all on natural gas and boiler 3 at 8760 hrs/yr and boilers 1and/or 2 for the remainder, all on No. 2 fuel oil. The allowable fuel consumption limit was based on the scenario providing the highest allowable fuel consumption, which was the No. 2 fuel oil scenario. A fuel consumption limit of 1,597,696 mmBtu/yr will be included in the permit.

CSU had requested a "bubbled" emission limit for NO_X and SO_2 for all three boilers together. The maximum emissions of PM, PM_{10} and CO for all three boilers together, exceed the PSD significance level (maximum based on the most conservative emission factors, design rate and 8760 hrs/yr or operation); therefore, the Division believes that the permit must include emission limits for those pollutants, in addition to limits on NO_X and SO_2. Since the permit will contain a fuel consumption limit for the boilers, the Division considers that the emission limits for the other criteria pollutants should be based on the fuel consumption limit and not based on actual emissions plus PSD significance level minus 1 ton. Again, permitted emissions would be based on the fuel providing the worst-case emissions. The following summarizes the permitted emissions for the other criteria pollutants that will be included in the permit.

Pollutant	Permitted Emissions (tons/yr)[1]	Allowable Emissions (tons/yr)[2]
PM	19.09	32.48
PM_{10}	13.31	19.91
SO_2	42.81	57.92
NO_X	127.69	127.69
CO	65.79	128.22
VOC	4.31	40.92

[1]permitted emissions are based on the allowable fuel consumption limit and the most conservative emission factor.
[2]allowable emissions are based on actual emissions (average of 03-04 and 02-03) plus the PSD significance level minus 1 ton/yr.

CSU had requested a "bubbled" emission limit for NO_X and SO_2 for all three boilers together. However, when boiler 1 was added to the facility, the facility was already a major stationary source and PSD review requirements potentially applied to the addition of boiler 1. When boiler 1 was initially permitted (initial approval issued 12/18/85), the Division recognized that boiler 1 was replacing two existing boilers and it appears that the Division may have taken this into account and considered that PSD review requirements did not apply. However, the analysis was not done appropriately. When the original Title V permit application was being processed, the Division recognized that there was potential PSD issues associated with boiler 1 and to address these issues, the Division included limits in the original Title V operating permit (issued October 1,

1998) for all three boilers to keep the PTE below 250 tons/yr and make the facility a synthetic minor source for PSD. This is discussed in the technical review document that supported the original Title V permit. However, when the Title V permit was modified (revision issued August 7, 2000), the Division realized that limiting the PTE of the boilers below 250 tons/yr did not address the PSD issues. The boilers are considered a listed source and therefore the threshold for major stationary sources is 100 tons/yr. As discussed in the technical review document for the August 7, 2000 revised Title V permit, emissions from the boilers could not be kept below 100 tons/yr. In processing that revision to the Title V permit, the Division again took into consideration the fact that boiler 1 had replaced two boilers (old boilers 1 and 2). The technical review document for the revision indicated that it would have been possible for CSU to net out of PSD review. The netting analysis was performed correctly and based on the permitted fuel consumption rate for boiler 1 the emission increase was below the PSD significance level. However, as part of the modification the Division increased the fuel consumption limit for boiler and subsequently the emission limits. The analysis in the technical review document for the August 7, 2000 revision demonstrated that in order to net out of PSD review, boiler 1 would have to take limits on hours of operation (i.e. fuel consumption limits), which essentially made the addition of boiler 1 synthetic minor for a major modification. Colorado Regulation No. 3, Part B, Section IV.D.3.b(iv) specifies that PSD review requirements apply at such time that a modification becomes a major modification solely by virtue of a relaxation in any enforceable limitation on the capacity of a source. Therefore, since boiler 1 was required to take operating limits in order to avoid PSD review, those limits cannot be exceeded and therefore, boiler 1 must have its own NO_X emission limit. In addition, it was an error for the Division to allow CSU to increase the fuel consumption limits for boiler 1 in the revised Title V permit. Therefore, the NO_X emission limit in the current Title V permit is not appropriate and must be revised.

The Division reviewed the netting analysis in the technical review document for the August 7, 2000 modified Title V permit. In this analysis, the Division based actual emissions on November 1982 – October 1983 and November 1983 – October 1984. CSU only had historic data on the total fuel consumption for the heating plant, but did not have data on the individual boilers, so the Division assumed the percent operating time for each boiler based on the design heat rate of the unit (i.e. the smaller boilers were run less time than the larger boilers). Typically actual emissions are to be based on the two years prior to the modification, although if another year is more representative then that year may be used. The Division reviewed the data and determined that November 1981 – October 1982 may be more representative than 82/83. In addition, the analysis for the modification did not base actual emissions on the worst -case fuel (EPA guidance document PSD/98). Therefore, the Division reviewed the previous analysis and determined that the following actual emissions for the boilers that were replaced:

	November 81 – October 82[1]		November 83 – October 84[1]		
Pollutant	Fuel[2] (mmBtu/yr)	Old Blr 1 and 2 Actual (tons/yr)	Fuel[2] (mmBtu/yr)	B.r 1 and 2 Actual (tons/yr)	Average Actual (tons/yr)
PM	Total = 751,243 old boilers 1 and 2 = 196,072.07	11.13	Total = 799,301 Old boilers 1 and 2 = 208,617.56	11.8	11.45
PM_{10}		11.13		11.8	1145
SO_2		139.2		148.2	143.7
NO_X		35.9		38.25	37.1
CO		8.07		8.6	8.34
VOC		0.5		0.56	0.53

[1]Actual emissions are based on "worst case" fuel. For PM, PM_{10}, NO_X and SO_2 worst-case fuel is #6 fuel oil. For VOC and CO worst-case fuel is natural gas. Note that emissions are based on current AP-42 emission factors.
[2]Previously #6 fuel oil was used as fuel for the boilers. The sulfur content of the fuel oil was presumed to be 1.34 weight %, per recent analysis submitted with historic boiler fuel data. The heat content of the fuel was presumed to be 150,000 Btu/gal per AP-42, Appendix A.

Based on the revised actual emissions, allowable emissions were re-calculated. Allowable emissions, for all but NO_X are based on the average actual emissions plus the PSD significance level minus 1 ton/yr. For NO_X, allowable emissions are based on the average actual emissions plus the PSD significance levels minus 0.1 tons/yr (i.e. 39.9 tons/yr). The revised allowable emissions for boiler 1 are as follows:

Pollutant	Average Actual Emissions for old boilers 1 and 2 (tons/yr)	Allowable Emissions for boiler 1 (tons/yr)	Permitted Emissions for Boilers 1-3 (tons/yr)
PM	11.45	35.45	19.09
PM_{10}	1145	25.45	13.31
SO_2	143.7	182.7	42.81
NO_X	37.1	77	127.69
CO	8.34	107.34	65.79
VOC	0.53	29.53	4.31

Since the total permitted emissions for PM, PM_{10}, SO_2, CO and VOC are below the allowable emissions for boiler 1, individual limits for these pollutants on boiler 1 are not necessary. However, boiler 1 must still have an individual NO_X emission limit. Note that boiler 1 was previously permitted at 80.3 tons/yr of NO_X. Therefore, only a small reduction in permitted NO_X emissions is necessary to address past PSD issues associated with this boiler. A review of recent inspection reports indicates that CSU should not have a problem meeting the lower NO_X limit for boiler 1.

<u>Change in Fuel Use Determination</u>

In their application to install a steam turbine, CSU estimated fuel usage based on Xcel Energy's meter for the heating plant, since they consider that meter more accurate. The Xcel invoices for the heating plant meter, provides the combined fuel consumption for all three boilers at the heating plant. In order to determine individual fuel consumption for each boiler, CSU used the individual boiler meters to determine the percentage of fuel consumed by each boiler and then multiplied that percentage by the heating plant fuel consumption on the Xcel invoice. The permit will be revised to reflect this new method of determining fuel consumption for the heating plant boilers.

Other Modifications

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Colorado State University Renewal Operating Permit with the source’s requested modifications. These changes are as follows:

Page following Cover Page

Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on the permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

The citation (above “issued to” and “plant site location”) on the page following the cover page provides the incorrect title for the state act. The title will be changed from “Colorado Air Quality Control Act” to “Colorado Air Pollution Prevention and Control Act”. In addition, the reference to specific dates has also been removed.

Added language specifying that the semi-annual reports and compliance certifications are due in the Division’s office and that postmarks cannot be used for purposes of determining the timely receipt of such reports/certifications.

Section I - General Activities and Summary

The language in Condition 1.1 was changed to reflect the attainment/non-attainment status of the Ft. Collins area.

In Condition 1.4, Conditions 13 and 17 were renumbered to 14 and 18 and Condition 21 in Condition 1.5 was renumbered to 22 due to the addition of a new general condition.

In Condition 1.4, General Condition 3.g (new general condition for general provisions) was added as a State-only requirement.

Revised Section 3 (PSD) and reversed the order of Conditions 3.1 and 3.2. In addition, revised the language in Condition 3.2 to more appropriately address PSD requirements following the addition of the steam turbine. Specifically, based on comments from EPA on another permit, removed the statement indicating that modifications up to this time have not exceeded the significance level and triggered PSD and/or non-attainment NSR review. In addition, since the attainment status of the Ft. Collins area has changed, the referenced to major non-attainment area NSR have been removed.

Based on comments made by EPA on another operating permit, the phrase “Based on the information provided by the applicant” was added to the beginning of Condition 4.1 (Accidental Release Prevention Program, 112(r)).

Added a “new” Section 5 for compliance assurance monitoring (CAM), note that no emission units are subject to CAM.

Section II - Specific Permit Terms

Section II.1, Boiler # 1

Clarification of Issues from Previous Permit Modification

During the processing of the original Title V permit application, prior to initial issuance (October 1, 1998), the source had indicated that they would likely be switching from No. 6 fuel oil to No. 2 fuel oil as back-up in the near future, so the Division included the use of both No. 6 and No. 2 fuel oil, with the No. 2 fuel oil use included as an alternative operating scenario. In the modified operating permit, issued August 7, 2000, the source had exhausted their supply of No. 6 fuel oil and only natural gas and No. 2 fuel oil were identified as fuels for the boilers. It appears that the Division never adequately addressed in either the technical review document for the original Title V operating permit or the technical review document for the modification, whether the fuel switch would trigger any additional applicable requirements such as NSPS or PSD review requirements. Therefore, the Division is using this opportunity to address that issue.

As a follow-up to the Division’s 1999 inspection of the facility, the source indicated in a letter dated September 30, 1999 that the switch from No. 6 to No. 2 fuel oil did not qualify as a “modification” for purposes of the NSPS, since the switch to No. 2 fuel oil did not result in an increase to any of the pollutants regulated by the NSPS (NO_X, SO_2 and PM) and that the physical changes to convert to No. 2 fuel oil were considered “routine maintenance, repair and replacement”. Specifically the physical changes included replacement of the plant fuel oil service pumps and associated piping/fittings due to age deterioration and obsoleteness. There were no physical changes made to the fuel injection or piping systems at any of the boilers except for a fuel valve replacement at Boiler #2 due to age. The Division agrees that the switch from No. 6 to

No. 2 fuel oil is not a modification under the NSPS requirements and did not trigger any NSPS requirements.

It was not clear whether the Division or the source ever investigated whether the fuel switch triggered PSD review requirements. Under the PSD rules, a physical change or change in the method of operation does not include use of an alternative fuel that the source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit. Although Boilers #2 and #3 were initially permitted in the original Title V operating permit, the Division restored the grandfathered status of these units in the modified operating permit issued August 7, 2000. Since these units were not permitted and as discussed above were capable of accommodating the No. 2 fuel oil, the switch from No. 6 to No. 2 fuel oil was not considered a physical change or change in the method of operation. An initial approval construction permit was issued on December 18, 1985 for Boiler #1 and the permit restricted the boiler to use of natural gas and No 6 fuel oil to be used only for standby during curtailment of natural gas. Therefore, even though Boiler #1 would be capable of accommodating No. 2 fuel oil, use of the fuel is restricted by a federally enforceable permit. However, the Division considers that with the Title V operating permit issuance, the Division included a limit of the consumption of fuel oil. In the revised Title V operating permit (issued August 7, 2000) the Division restricted fuel consumption to 275,000 gal/yr, which equates to about 244 hrs/yr of operation at the maximum fuel oil consumption rate of the unit and at that level, all pollutant emissions from No. 2 fuel oil burning are much less than the PSD significance levels. Therefore, the Division considers that the fuel switch from No. 6 to No. 2 fuel oil did not trigger any PSD review requirements.

<u>Fuel Sulfur Content and Sampling</u>

In a previous letter (January 11, 2001) to the Division, the source indicated that their fuel supplier had indicated that fuel oil in the Colorado market met the definition of “low sulfur oil” (i.e. sulfur content no greater then 0.05% by weight). They also indicated that “low sulfur oil” would comply with all the fuel sulfur requirements of their permit and that further fuel sampling would be redundant. In addition, the source indicated that they would be willing to use a sulfur content of 0.05% to calculate emissions using the mass balance approach. The Division replied to the source’s letter (March 9, 2001) and indicated that although we would agree that use of “low sulfur oil” would most likely ensure that the SO_2 limitations are met, that some sampling or certification from the supplier would be required to verify the fuel sulfur content is no greater than 0.05% and that sampling would be necessary to determine the heat content and density of the fuel oil, since the calculation method is based on mass balance rather than AP-42 emission factors. In addition, the Division inspector indicated in her inspection report (dated September 4, 2002), as a suggestion for the renewal permit (page 7 of the report) “to allow use of max fuel oil sulfur content and presume compliance with the emission limitations as long as the actual value does not exceed the APCD set limit”.

Therefore, in order to address the information in the source’s January 11, 2001 letter and the inspector's suggestion, the Division is including a fuel sulfur limit of 0.05 weight percent in the permit and specifying that compliance shall be met provided the fuel oil supplier's certification indicates that the fuel oil has a sulfur content no greater than 0.05 % by weight.

The current permit requires that the source calculate SO_2 emissions using the density and heat content of the fuel oil. In order to remove any further fuel sampling requirements from the permit, the Division has revised the permit to require that SO_2 emissions be calculated using AP-42 emission factors, which only require the quantity of fuel consumed and the sulfur content of the fuel. Note that if the source prefers to use the mass balance method, they should indicate so during the pre-public comment review period and the Division will revise the renewal permit. Note however, that if the material balance method is used the source will require additional fuel sampling to verify the heat content and density of the fuel oil.

Miscellaneous

Revised Condition 1.1 to include annual SO_2 emissions and to calculate emissions in "tons/month" rather than "lbs/month". In addition, the AP-42 emission factor for SO_2 was added to the table. Note that the AP-42 emission factor is based on the weight percent sulfur, however, the numerical value in the table is based on a weight percent sulfur of 0.05%. Finally, the citation was revised to cite the Reg 3 provisions that allow combined construction/operating permit processing and to indicate that emissions were increased based on the APEN submitted on March 8, 2000.

Table 1.1 (in Condition 1.1) lists the emission factors for the boilers. The emission factors in this table for PM and PM_{10}, only include filterable PM, not condensable PM. The table was revised to include condensable PM in the PM and PM_{10} emission factors. In addition, the emission factors were converted to units of lbs/MMBtu.

Revised Condition 1.2 to include the numerical PM limitation in the table and made additional minor language changes to the text. Since the permit already requires the source to use the maximum fuel input rating on the boiler to calculate the PM limit, it makes more sense to include this limit in the table.

Revised Condition 1.3 to indicate that the SO_2 limitation (Reg 1 lbs/mmBtu limit) applies only when burning fuel oil.

Revised the citation in Condition 1.5 to cite the Reg 3 provisions that allow combined construction/operating permit processing and to indicate that fuel consumption limits were increased based on the APEN submitted for the steam turbine modification.

The order of the opacity requirements was reversed and the language was revised to more closely match the language in the regulation. In addition, the opacity requirements were grouped into one condition, Condition 1.6. In addition, added language indicating that an opacity violation was considered to occur from the time an opacity reading was taken that showed non-compliance until an opacity reading is taken that shows compliance. In addition, the opacity monitoring requirements were revised to remove the statement that no opacity observation was required if there was no startup during the period. This language presumes that the boiler would have to startup on fuel oil in order for fuel oil to be burned, which is not necessarily correct.

Removed the requirement to submit a startup parameter report in Condition 1.6.3. The source has fulfilled this requirement. The startup parameter report will be included in Appendix G of the permit.

Added the requirement to record startups, shutdowns and malfunctions under the state-only NSPS general provisions (Condition 1.8). This requirement is from 40 CFR Part 60 Subpart A § 60.7(b), as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A.

Section II.2 – Boilers #2 and #3

CSU submitted additional information on June 1, 2004 to add a steam turbine to the heating plant and with this modification CSU took operating limits on all of the heating plant boilers. Therefore, Section II.2 was removed and all the boilers are grouped together under Section II.1 of the permit.

Section II.3 – Incinerators

<u>Clarification of Issue From Previous Permit Modification</u>

Questions have come up on several occasions regarding whether or not either of these incinerators would be subject to the Emission Guidelines and Compliance Times for Hospital/Medical/infectious Waste Incinerators (40 CFR Part 60 Subpart Ce) and so the applicability of these units will be discussed here to hopefully clarify the situation and prevent further confusion. These guidelines apply to any hospital/medical/infectious waste incinerator (HMIWI) for which construction commenced on or before June 20, 1996. A HMIWI is defined in 40 CFR Part 60 Subpart Ec, § 60.51c as “any device that combusts any amount of hospital waste and/or medical/infectious waste”. The CDC and ADL incinerators burn only animal carcasses and the associated bedding or containers. Medical/Infectious waste as defined in 40 CFR Part 60 Subpart Ec, § 60.51c, includes “animal waste including contaminated animal carcasses, body parts, and bedding that were known to have been exposed to infectious agents during research (including research in veterinary hospitals), production of biologicals or testing of pharmaceuticals”. The incinerators at CSU combust animal carcasses that have been exposed to infectious agents during research, therefore, although the CSU incinerators burn only pathological waste, some of that pathological waste is classified as medical/infectious and therefore the CSU units are HMIWI and are further classified as small HMIWI (capacity of each unit is less than or equal to 200 lbs/hour). However, a combustor is not subject to the provisions of 40 CFR Part 60 Subpart Ce during periods when only pathological waste is burned, provided the owner or operator notifies the Division and the EPA and keeps records on a calendar quarter of the periods of time when only pathological waste is burned (40 CFR Part 60 Subpart Ce § 60.32e(b)). Since CSU only burns pathological waste and has notified the Division and the EPA (November 29, 1999 letter) and is keeping quarterly records, although the units are HMIWI they are only subject to the aforementioned notification and recordkeeping requirements. Conditions 3.4.1 and 3.4.2 of the current permit indicate that the units may only burn pathological waste and that burning of other hospital or medical/infectious waste, that is not also pathological, will result in the units being subject to the full provisions of 40 CFR Part 60 Subpart Ce.

<u>Miscellaneous</u>

Removed the statement under the table header indicating which requirements are state-only and added language to the table and text indicating which requirements are State-only. Note that the Division considers that except for the Reg 1 opacity requirements, the charge rates and the restriction on burning pathological waste to avoid further requirements under 40 CFR Part 60 Subpart Ec, all requirements are state-only. Note that although there may be some requirements that are not directly from Reg 6, Part B (i.e. operator requirement in Condition 3.7), it is provided to directly monitor compliance with a state-only requirement therefore, the Division considers it a state-only requirement.

The Division removed the performance test requirements (Condition 3.8). The initial performance tests were conducted on these units on December 20, 1999 and January 20, 2000. The results indicated that for the most part both incinerators were well below the limitations (PM emissions from the ADL were 0.0589 gr/dscf @ 7% O_2, on run 3, while the standard is 0.08 gr/dscf @ 7% O_2). The monitoring requirements in the permit are sufficient to not require further performance tests. However, it should be noted that although not specifically indicated in the permit, that the Division may require performance tests at any time as specified in the Common Provisions Regulation (general condition 3.c) or as indicated in Regulation No. 1, Section III.B.3 (when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated).

Revised the language under Condition 3.6, regarding monitoring compliance with the retention time requirement since the performance tests have been conducted.

The language in the opacity requirements was revised to more closely match the language in the regulation.

Added language to Condition 3.9.3 (10% opacity requirement) indicating that an opacity violation was considered to occur from the time an opacity reading was taken that showed non-compliance until an opacity reading is taken that shows compliance. In addition, added language to Condition 3.9.3 indicating that a method 9 visible emission observation was not required if the incinerator was not operated during the annual period.

Removed the requirement to maintain records of the occurrence and duration of any startup, shutdown and malfunction from the opacity requirement in Condition 3.9.3. This requirement was included in the NSPS general provisions (Condition 3.12) as discussed below.

The citation was revised in Condition 3.10 to cite the Reg 3 provisions that allow combined construction/operating permit processing and to indicate the basis for the revisions (i.e. APEN or letter submitted on a given date).

The requirement to submit ash removal and handling procedures (Condition 3.11.3) was removed since the procedures have been submitted. The procedures will be included in Appendix H of the permit and the permit shall specify that the source follow the ash removal and handling procedures to minimize visible emissions during removal and transport to disposal.

Added the requirement to record startups, shutdowns and malfunctions under the state-only NSPS general provisions (Condition 3.12). This requirement is from 40 CFR Part 60 Subpart A § 60.7(b), as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A.

Section II.4 – Storage Tanks

The four storage tanks were included in the August 7, 2000 revised Title V operating permit because the tanks were subject to recordkeeping requirements in 40 CFR Part 60 Subpart Kb. Effective October 15, 2003, revisions were made to NSPS Subpart Kb and under these revisions tanks that have a capacity greater than 75 m^3 (19,813 gal) but less than 151 m^3 (39,889 gal) storing a liquid with a maximum true vapor pressure less than 15 kPa are exempt from the provisions of 40 CFR Part 60 Subpart Kb. Since the tanks have emissions below APEN de mimims levels and since the tanks are no longer subject to 40 CFR Part 60 Subpart Kb, these tanks are no longer subject to APEN reporting requirements and can be considered insignificant activities. Therefore, these tanks have been removed from Section II of the permit and are now included in Appendix A.

Section III – Permit Shield

The citation for the permit shield is incorrect. The reference to Part A, Section I.B.43 should be Part A, Section I.B.44 and the reference to Part C, Section XIII should be Part C, Section XIII.B.

Based on comments made by EPA on another permit, the following statements were added after the introductory sentence in Section 1 “This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modification or reconstruction on which construction commenced prior to permit issuance.”

Based on comments made by EPA on another permit, the following phrase was added to the beginning of the introductory sentence “Based upon the information available to the Division and supplied by the applicant”.

Revised the permit shield for 40 CFR Part 60 Subpart Kb to reflect the revisions made to the requirements in 40 CFR Part 60 Subpart Kb.

Section IV - General Conditions

Added an “and” between the Reg 3 and C.R.S. citations in General Condition 3 (compliance requirements).

Added language from the Common Provisions (new condition 3). With this change the reference to “21.d” in Condition 20 (prompt deviation reporting) will be changed to “22.d”, since the general conditions are renumbered with the addition of the Common Provisions.

Removed the Upset Provisions from Condition 4 (emergency provisions and upset conditions), since the upset provisions are included in the common provisions.

The citation in General Condition 7 (fees) was changed to cite the Colorado Revised Statue. In addition, any specific identification of a fee (i.e. $100 APEN fee) or citation of Reg 3 was removed and replaced with the language “…in accordance with the provisions of C.R.S. [appropriate citation].”

The phrase “Part A” was added to the citation for Condition 13 (odor). Colorado Regulation No. 2 was revised and a Part B was added to address swine operations. Colorado Regulation No. 2, Part B should not be included as a general condition in the operating permit.

The citation in General Condition 16 (open burning) was revised. The open burning requirements are no longer in Reg 1 but are in new Reg 9. In addition, changed the reference in the text from “Reg 1” to “Reg 9”.

Added the requirements in Colorado Regulation No. 7, Section V.B (disposal of volatile organic compounds) to General Condition 28.

Appendices

Added the four (4) 30,000 gal No. 2 fuel oil storage tanks to the insignificant activity list in Appendix A.

Although the source had submitted a list of insignificant activities (i.e. tanks, boilers and emergency generators), the Division did not include the list in the original Title V permit. It has been the Division’s policy to include insignificant activity lists as an aid to the inspector. Therefore, the list submitted with the original Title V permit application was included in Appendix A of the permit.

Appendix B and C were replaced with revised Appendices.

Removed the four (4) 30,000 gal No. 2 fuel oil storage tanks from the tables in appendices B and C.

The EPA addresses in Appendix D were corrected.